

PLANNING AND IMPLEMENTATION OF AN ALKALI-SURFACTANT-
POLYMER (ASP) FIELD PROJECT

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By
Troy French

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Performed Under Contract No. DE-AC22-94PC91008
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National Petroleum Technology Office
U. S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

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Planning and Implementation of an ASP (Alkali-Surfactant-Polymer) Field Project

1.0 ABSTRACT

The Warden ASP project has progressed from the initial planning stage to construction of an injection plant. An ASP chemical system was designed based on laboratory evaluations that included interfacial tension, mobility requirements, rock-alkali interaction, fluid compatibilities, and core tests. Field cores were obtained from the Permian No. 5 and No. 6 sands on the Warden lease in Sho-Vel-Tum oil field.

A separate tank battery for the pilot pattern area was installed, and a field tracer test is currently being evaluated. Tracer test results to date indicate that there is no major fracturing in the No. 5 sand. There is indication, however, of some channeling through the high permeability sand. The field injection plant was designed, and construction is in progress. Several variations of injection plant design have been evaluated. Some plant design details, such as alkali storage, were found to be dependent on the availability of used equipment and project budget. The surfactant storage facility design was shown to be dependent on surfactant rheology. Chemical injection is scheduled for December 1997.

2.0 INTRODUCTION

Many oil field operators find it increasingly difficult to recover substantial amounts of oil economically from U.S. fields. As fields mature, production rates eventually become uneconomic. This occurs despite the fact that a large fraction of the original oil resource yet remains in U.S. oil fields. BDM Petroleum Technologies is conducting research on ASP flooding as a part of the U.S. Department of Energy (DOE) plan to maximize the economic producibility of our domestic oil resource. ASP flooding shows promise of being cost-effective because alkali, in addition to reinforcing the activity of surfactants, reduces the depletion of surfactant and polymer that occurs because of retention in the reservoir. The field viability of surfactant-enhanced alkaline flooding has been given a boost by a small number of field experiments performed in the United States (Clark et al. 1988; Falls et al. 1992; Meyers et al. 1992).

A surfactant-enhanced alkaline field flood that is properly designed with weak alkali and a polymer (for mobility control) should be effective for reducing residual oil saturation and for increasing the rate of oil production. Near-term application of a promising improved oil

recovery (IOR) technology is consistent with DOE's oil research strategy and has been given high priority by DOE. The benefits of conducting a project include the following:

- Acquiring the information and data that will help to demonstrate the applicability of surfactant-enhanced alkaline flooding as a cost-effective IOR method
- Transfer of surfactant-enhanced alkaline flooding technology to the petroleum industry
- Gaining experience and data on designing and applying this technology that will assist independent producers in sustaining production from mature producing oil fields rather than abandoning marginal wells

3.0 PROJECT DESCRIPTION

The objectives of this project are to select a suitable field site, select a surfactant-enhanced alkaline chemical formulation for the site, and establish cooperative business relationships that will lead to field application in 1997. Selected reservoir screening criteria were used to identify potential candidate reservoirs. Field trips were taken to the sites to obtain data and samples. Reservoir characterization techniques were used for the most promising candidates to help predict the performance of the surfactant-enhanced alkaline flooding process.

Laboratory experiments conducted with brine, oil, and core, if available, from selected sites were used to design ASP chemical systems suitable for field application. Also, ASP chemical systems were formulated specifically for use at selected field sites. Final screening, site selection, and design have been completed and will be followed by field application.

The present status of the project is continued construction of the field injection facility. Because the design and construction of such an injection facility may present a number of problems for companies that have not previously undertaken such work, this topical report will focus on addressing these problems and therefore to facilitate injection plant construction for the independent petroleum sector.

Some of the accomplishments for the project this year are:

- Selection of a reservoir for an ASP field pilot test
- Establishment of a working relationship with field operator
- Drilling and completion of an injection well
- Recovery and analysis of 97% of the core
- Design of an ASP chemical system for field use
- Construction of separate tankage for the pilot pattern area
- Field tracer test (evaluation and sampling in progress)
- Design of the injection plant
- Construction (in progress) of the injection plant

4.0 FIELD SITE

Experiments conducted with cores and fluids from a reservoir in Sho-Vel-Tum field, location shown in Figure 1, indicate that the Permian sand is a good candidate for ASP flooding. The field site, operated by Le Norman Energy, is 16 miles east of Duncan, Oklahoma. The oil is a moderately heavy crude. Oil gravity is 26.4° API and in-situ oil viscosity is 41.3 cp at 30°C reservoir temperature. Oil acid number is 0.28 mg KOH/g oil. The field is drilled on 2.5-ac spacing, and production is from two sands at depths of approximately 677 ft and 709 ft, respectively. Net pay in the upper sand is approximately 12 ft thick; a second sand is about 10 ft thick. Several feet of shale separate the two sands. Average permeability of the sands is in the range of 500 to 700 md. Reservoir salinity is low, and this is at least partly because of many years of waterflooding with freshwater.

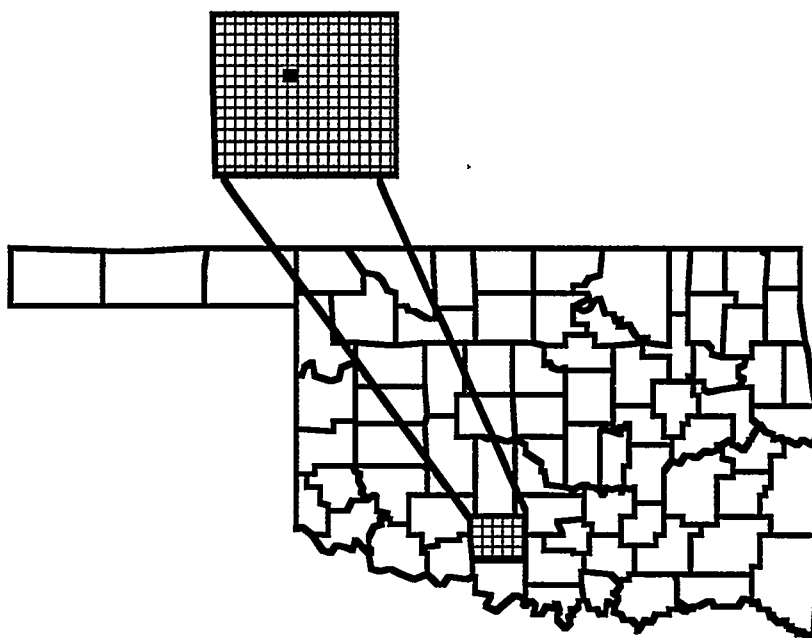


Figure 1 Field Project Location 16 Mi East of Duncan, Oklahoma

5.0 INJECTION WELL AND CORE ANALYSIS

An injection well was drilled and completed in Sho-Vel-Tum oil field. Approximately 58 ft of core was obtained from the well with two 30 ft core barrels. Because of the friable nature of the sandstone, a special inner core barrel made of aluminum alloy was used. Considering the fragile nature of the sands, the 97% recovery of core was extremely good. The missing two feet of core were lost from the bottom of the second core because of drilling crew error. The core was removed from the site still in the two core barrels. After removal from the site, the core barrels were cut into 3-ft sections, and each 3-ft section was capped with a neoprene end piece. The core was then examined with X-ray tomography while still in the core barrel sections. The cores were then removed from the core barrels, and core plugs were cut for the analytical procedures. The cores are from the Permian No. 5 and the Permian No. 6 sands. The Permian No. 5 (upper

sand) was the primary target for the field project, but the Permian No. 6 (lower of the two sands) appears to be the best candidate for the chemical flooding project. The routine core analytical results are given in Table 1.

Table 1 Warden Well ERI No. 1 Core Analysis

Depth, ft	So, %PV	K, md	Depth, ft	So, %PV	K, md
676	4	<1	701	3	imp.
677	11	3	702	2	1
678	38	148	703	2	<1
679	30	34	704	-	shale
680	44	2	705	-	shale
681	48	41	706	-	shale
682	32	252	707	-	shale
683	26	40	708	24	<1
684	37	437	709	46	60
685	30	63	710	42	381
686	34	24	711	39	54
687	42	4	712	42	465
688	30	182	713	41	178
689	33	501	714	49	602
690	37	412	715	37	68
691	33	1443	716	56	301
692	36	1245	717	46	978
693	29	1185	718	57	1790
694	36	126	719	55	3227
695	12	18	720	33	350
696	20	25	721	23	4
697	27	4	722	34	63
698	30	56	723	29	443
699	17	3	724	Bottom of core	

Weighted Average (19 ft)

So = 32.6% PV
K = 300 md
S_{owf} = 28.3% PV

Weighted Average (15 ft)

So = 41.9% PV
K = 800 md
S_{owf} = 26.9% PV

The upper sand (Permian No. 5) consists of about 12 net ft of very porous sandstone. Average current oil saturation was 32.6% PV of oil. Average permeability is about 300 md. There is about 4.3% mobile oil, as the ultimate residual from waterflooding is 28.3% PV. Oil saturation is considerably higher in the lower sand (Permian No. 6). Current oil saturation there is about 41.9% PV. This means that there is about 15% PV of mobile oil, because the ultimate waterflood potential is down to an oil saturation of about 26.9% PV. Well logs indicate that this sand is probably about 10 net ft in thickness.

Table 2 shows the relative abundance of minerals in the upper sand, which was the primary target for the project. Clay minerals analysis is important to this project from several aspects (French and Burchfield 1990). Most important, minerals analysis indicates a mineral's reactivity to alkalis. There is 3% kaolinite in the sample, which means that some reactivity to alkali is expected. The laboratory evaluations discussed later in this report indicate moderate reactivity to alkali.

Table 2 Warden Well ERI No. 1 Core Mineral Analysis

Mineral Constituents	Relative Abundance, %
Quartz	94
Plagioclase feldspar	trace
K-Feldspar	trace
Dolomite	1
Siderite	trace
Kaolinite	3
Chlorite	trace
Illite/mica	1
Mixed-layer illite/smectite	1
% Illite layers in mixed-layer illite/smectite	45-55

Figure 2 shows a conception of the upper (Permian No. 5) reservoir in the vicinity of the injection well. The sand thickness in the illustration represents gross pay, rather than net pay. This conception is based on core analysis and well logs at the injection well, and old well logs from the surrounding production wells. The major feature of the sand is that about 8 net feet of highly permeable sand (100 md) is above a few feet more of even higher permeability sandstone (1,300 md). If one will examine the core analysis data for the lower (Permian No. 6) sand given in Table 1, it will be noticed that the structure of the lower sand is remarkably similar to that of the upper reservoir. The main difference is that the lower sandstone reservoir contains sand layers that have even higher permeabilities.

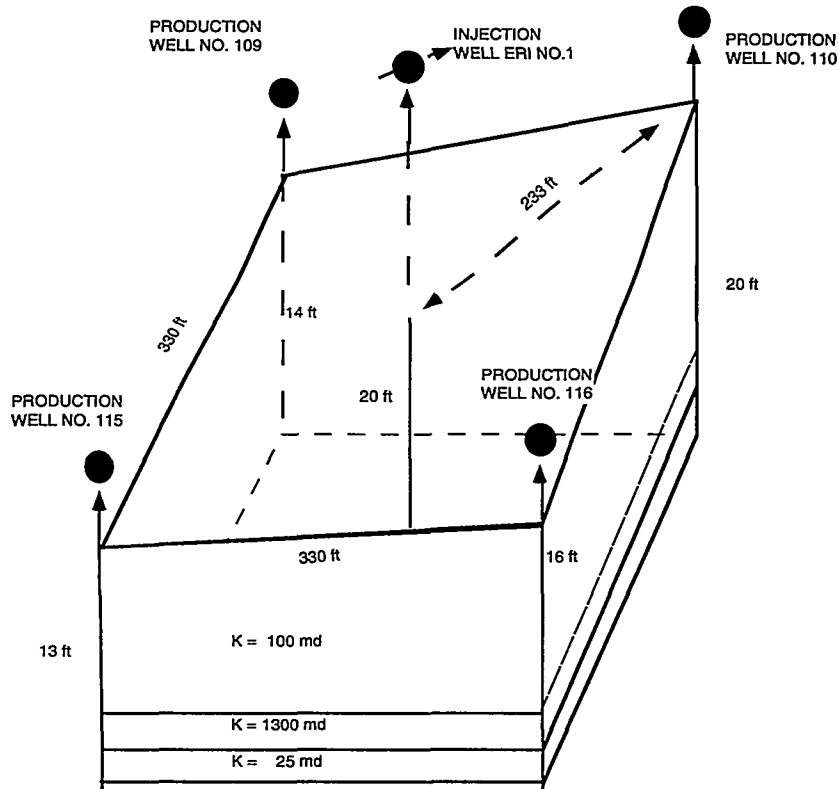


Figure 2 Permian No. 5 Sand Permeability Distribution

All of the data from well logs and core analyses indicate that these Permian sands are good candidates for ASP flooding. The two sands appear to be separated by a sealing shale/clay layer. Therefore either, or both, sands appear floodable.

6.0 WELL PATTERN AND TRACER TEST

The injection well that was drilled and completed in Sho-Vel-Tum oil field was perforated into two oil-bearing sands. Production wells in the pattern were tested to determine if the lower sand (Permian No. 6) is open. Upon completion, the injection well was connected to the Warden Unit saltwater injection facility for one week at an injection rate of 300 barrels daily. One part of this process was to conduct spinner surveys at the injection well. Production wells 109, 110, 115, and 116, which are shown in Figure 3, were acid treated. Spinner surveys indicated that the lower sand was not taking fluid. The reason for this is unknown at this time. After completion of these objectives, 21 bbl of 50% IPA (isopropanol) were injected into the injection well, and the pilot producers and surrounding wells are currently being monitored for signs of premature breakthrough.

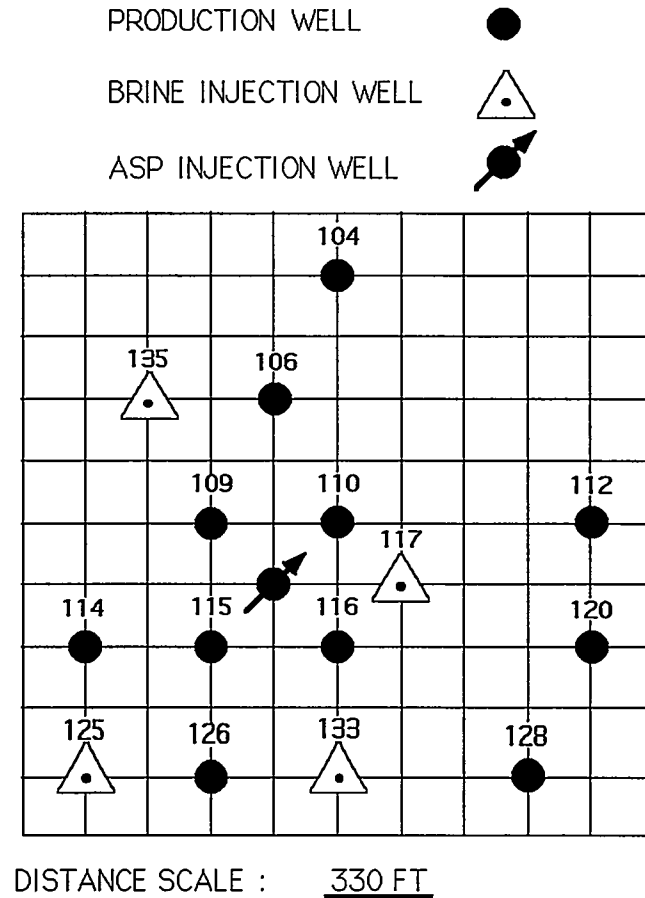


Figure 3 Field Tracer Test Well Pattern

Pattern and surrounding wells have been monitored for tracer breakthrough for 1.5 months. The last set of samples that were analyzed indicated increasing alcohol concentration in well 115 after 3 weeks of injection. This indicates preferential flow through the highest permeability sands, rather than a major fracture. The tracer show at well 115 is consistent with fluid production rates at the adjacent production wells. All wells are being pumped-down (at capacity), and well 115 is producing the most fluid. Well 115 also showed a marked response shortly after beginning tracer injection in well ERI No. 1. This indicates that, with further evaluation, it is likely that a small profile modification treatment to equalize fluid movement may be desirable before chemical injection is commenced.

7.0 LABORATORY EVALUATIONS

Numerous laboratory evaluations are needed before a field experiment can be properly designed and have a high chance of success in the oil field. Some of the laboratory evaluations that are needed include interfacial tension between reservoir oil and injected fluids, fluid compatibilities

(both in the reservoir and at the injection plant), rock-alkali interactions (basically consumption measurements), mobility control design, and oil recovery (coreflood) testing.

Dynamic interfacial tension (IFT) was measured between Warden produced oil and several commercial surfactants using a spinning drop interfacial tensiometer. IFT measurements were recorded several times for 30 minutes after contacting the oil and surfactant mixture. Very low IFT values were measured for some of the alkaline surfactant mixtures. The data from IFT experiments were compared with observations from phase behavior tests which were conducted by mixing equal volumes of alkaline surfactant mixtures and Warden crude oil. Alkaline surfactant mixtures that contain relatively low surfactant concentrations typically do not solubilize a large amount of oil, but rather form temporary macro-emulsions. Therefore, the primary evaluation of the phase behavior tests was based on the emulsification observed during agitation and during the time interval shortly after agitation. Very low IFT is usually indicated by brown-chocolate color emulsions that slowly coalesce after agitation. All of the alkaline surfactant mixtures were formulated in Velma rural water (from Velma, Oklahoma, a small town near the test site) which will be used for the field test. Surfactant concentrations given in this report represent actual (active) concentration of the surfactant in the mixtures. For example, if a commercial surfactant was 50% active, it required 2 g of bulk surfactant in 100 g to produce 1% surfactant concentration. All surfactant mixtures also contained 0.30% sodium tripolyphosphate (STPP), which eliminated precipitation in the rural water because of hardness. Elimination of precipitation is expected to facilitate injection into the reservoir because of the fact that the injection plant's filtration system will then require minimal maintenance.

After preliminary screening, Witco-2094, Witco-HL, ORS-41, and ORS-62 surfactants were selected for further testing. The IFT between alkaline mixtures that contained Witco-2094 and Warden oil are shown in Figure 4. IFT values were measured as low as 4×10^{-5} mN/m for 2.75% Na_2CO_3 concentration. However, at dynamic time values less than 15 minutes, IFT values are about the same for carbonate concentrations between 2.25% and 3.00%. Phase behavior tests indicated that the optimum carbonate concentration is near 2.25% Na_2CO_3 . The IFT data in Figure 5 are also of interest because they demonstrate the necessity of properly obtaining and properly handling field oil samples. Note that the IFT behavior of the optimized alkaline surfactant formulation deteriorated badly when light ends escaped from the oil. Therefore, all oil samples used for testing were periodically monitored to make sure that optimum IFT behavior was maintained with oil samples used for coreflood experiments.

During propagation through an oil reservoir, the chemical slug will be diluted by contact with formation brine. Experiments were therefore performed to determine the effect of dilution on IFT. Figure 6 shows the effect of dilution on the IFT between Warden oil and alkaline Witco 2094 surfactant. Relatively low IFT values were measured even after the alkaline surfactant was greatly diluted by reservoir brine. IFT values did not increase to 10^{-2} mN/m until after surfactant concentration was diluted to less than 0.2% concentration.

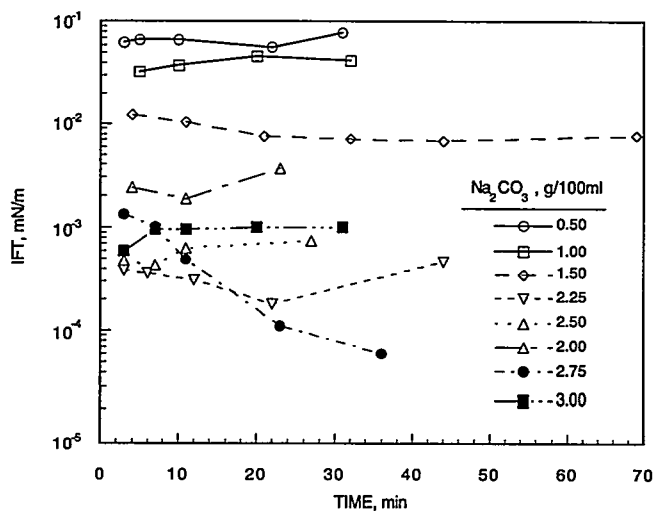


Figure 4 Interfacial Tension between Warden Stock Tank Oil and a Mixture That Contains 0.50% Witco-2094 Surfactant, 0.30% STPP, and Varying Amounts of Na_2CO_3 in Velma Rural Water

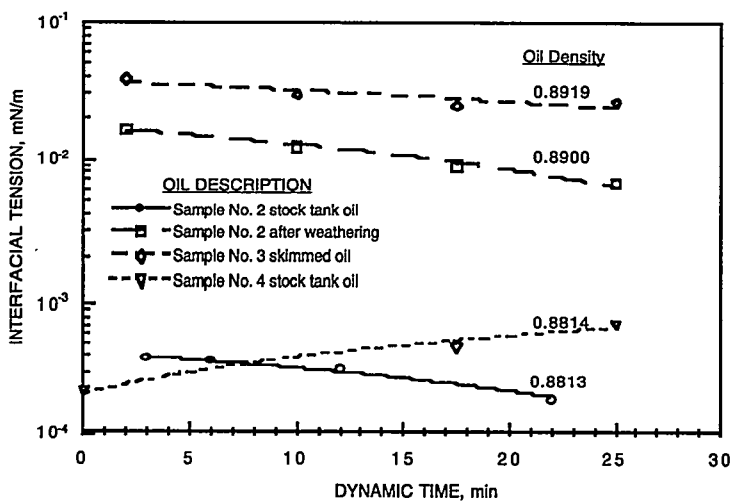


Figure 5 Interfacial Tension between Warden Oil Samples and Alkali-Surfactant

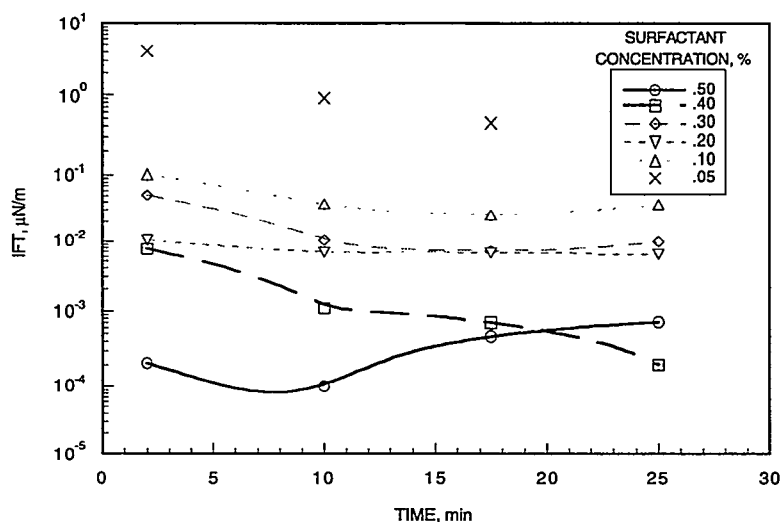


Figure 6 Interfacial Tension between Warden Stock Tank Oil and a Mixture That Contains Witco-2094 Surfactant, 0.30% STPP, and 2.25% Na₂CO₃ in Velma Rural Water

The IFT between Warden oil and ORS-41 surfactant are shown for two surfactant concentrations in Figures 7 and 8. Figure 7 shows the IFT behavior for 0.1% surfactant. Because even lower IFT values at early dynamic time are desirable, another alkaline surfactant formulation that contained 0.5% surfactant was tested (Figure 8). With 0.5% surfactant and 2.25% Na₂CO₃ concentration, early time dynamic IFT (at 2×10^{-6} mN/m) was very favorable for oil mobilization. Phase behavior observations also indicated optimum 2.25% Na₂CO₃ concentration.

An optimum 2.25% Na₂CO₃ concentration is considered to be on the high side of good economics during a field test. Therefore, three other chemical systems were tested in an effort to reduce optimum Na₂CO₃ concentration to less than 2%. Witco-2094 surfactant was blended with Witco-HL surfactant, which has slightly higher molecular weight. Blends containing from 30% to 70% of each surfactant were tested. Neither IFT nor phase behavior observations indicated that sufficiently low IFT values were achieved with HL/2094 blends. Witco 2094 was also blended with 0.5% isobutyl alcohol (IBA). Figure 9 shows the IFT measurements, with NaCl being used for ionic strength adjustment. Optimum concentration was 1.5% Na₂CO₃ without any NaCl being required for further ionic strength adjustment. Phase behavior observations were consistent with optimum 1.5% Na₂CO₃ concentration for the mixture containing IBA and Witco-2094.

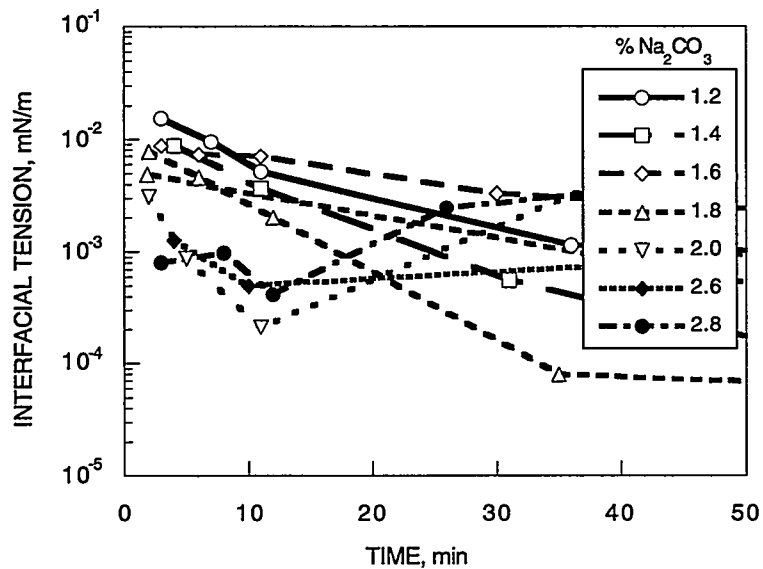


Figure 7 Interfacial Tension between Warden Stock Tank Oil and a Mixture That Contains 0.10% ORS-41 Surfactant, 0.30% STPP, and Varying Amounts of Na_2CO_3 in Velma Rural Water

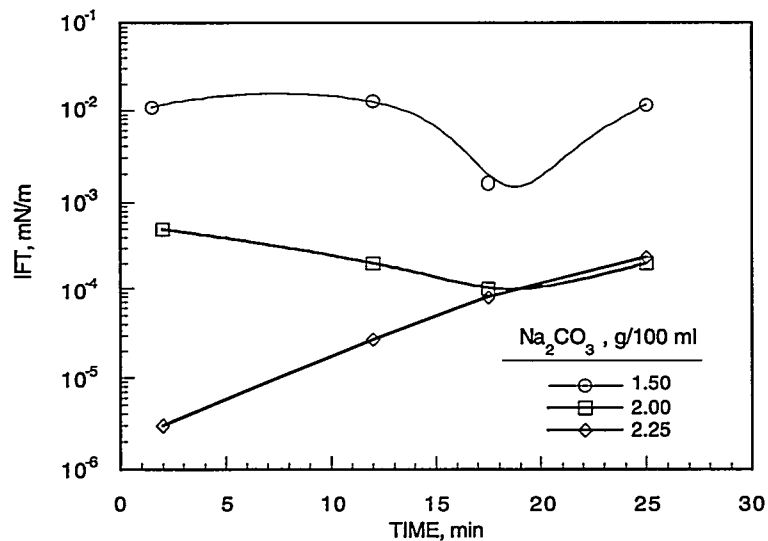


Figure 8 Interfacial Tension between Warden Stock Tank Oil and a Mixture That Contains 0.50% ORS-41 Surfactant, 0.30% STPP, and Varying Amounts of Na_2CO_3 in Velma Rural Water

Researchers here were furnished with another surfactant from Oil Chem Technologies, Inc. (OCT) with slightly higher molecular weight than the ORS-41. This surfactant, ORS-62, is probably the most promising for use in the Warden pilot test. Figure 10 shows the dynamic time IFT for alkaline 0.5% ORS-62 and Warden oil. Ultra-low (2×10^{-5} mN/m) IFT values were measured with 1.6% Na_2CO_3 in Velma water. Unfortunately, the IFT between ORS-62 and Warden oil appears to be more adversely affected by dilution with synthetic formation brine than for other surfactants. Results are shown in Figure 11. The explanation for the increased sensitivity to dilution with produced brine may be that the ORS-62 surfactant is actually less sensitive to divalent ions in the brine. Therefore, the effect of decreasing Na_2CO_3 concentration (through dilution) below optimum is more pronounced than with Witco-2094. With Witco-2094, it may be that increasing ionic strength because of hardness ions in the dilution brine compensates for loss of ionic strength because of the dilution of Na_2CO_3 . If this is so, then slightly higher than optimum Na_2CO_3 concentration may be the best choice for achieving good oil recovery with alkaline ORS-62 surfactant.

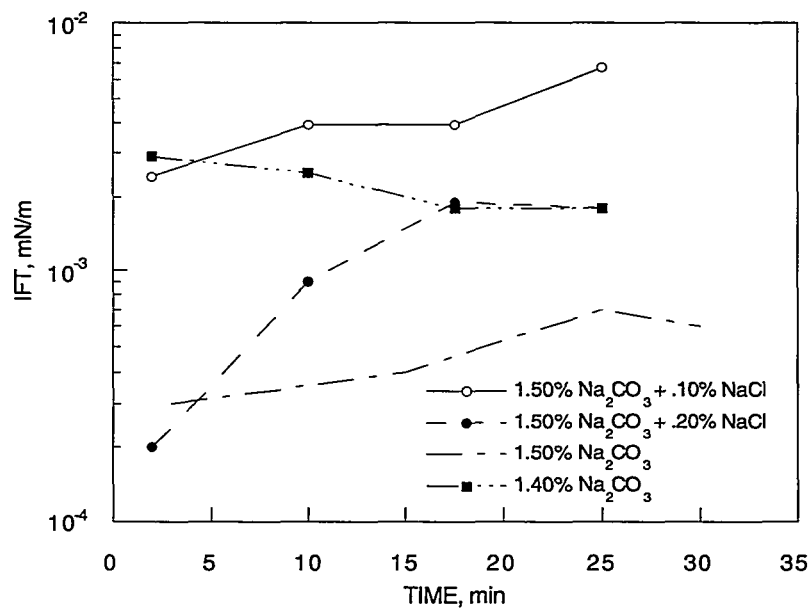


Figure 9 Interfacial Tension between Warden Stock Tank Oil and Mixtures That Contain 0.50% Witco-2094 Surfactant, 0.50% IBA, and 0.30% STPP in Velma Rural Water

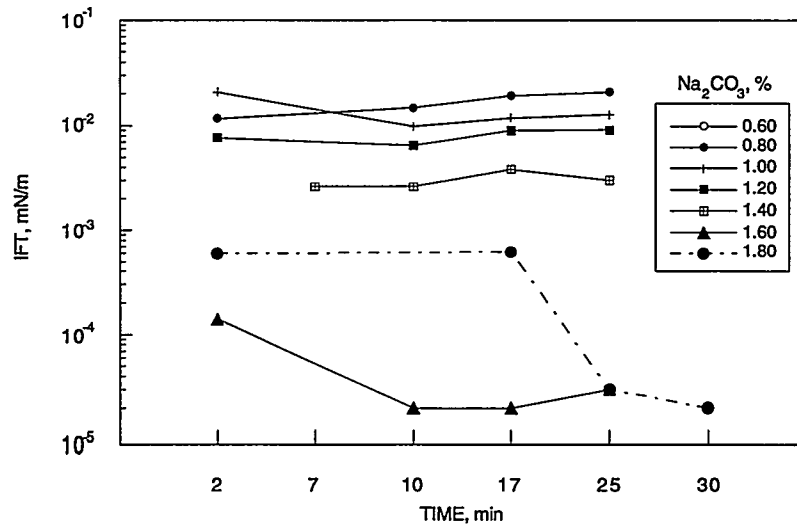


Figure 10 Interfacial Tension between Warden Stock Tank Oil and a Mixture That Contains 0.50% ORS-62 Surfactant, 0.30% STPP, and Varying Amounts of Na_2CO_3 in Velma Rural Water

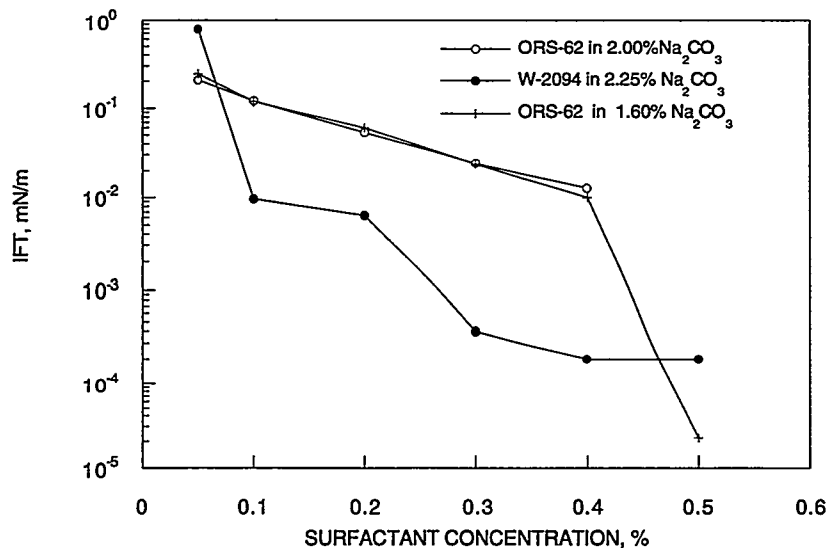


Figure 11 Interfacial Tension between Warden Stock Tank Oil and Optimized 0.50% Surfactant Mixtures—Dilutions with Synthetic Produced Water and Degree of Dilution Indicated by Surfactant Concentration after Dilution

The mineral constituents (Table 2) of the Permian 5 sand are quartz (94%), kaolinite (3%), dolomite (1%), illite/mica (1%), mixed layer illite/smectite (1%), plagioclase feldspar (trc), K-feldspar (trc), siderite (trc), and chlorite (trc). The minerals content of the sand appears to be compatible with the use of mild alkalis in the field project. Only kaolinite has appreciable short-term reactivity to alkalis, and that is predominantly with the stronger alkalis such as sodium hydroxide. The low concentration of smectite indicates small ion-exchange capacity. From the minerals analysis, it would be predicted that consumption of mild alkalis such as sodium carbonate would be within acceptable limits for field use.

An experiment to determine the extent of alkali consumption by reservoir rock was completed. Figure 12 shows the results of long-term measurements with alkali and field core. The experiment was conducted with 0.010 N Na_2CO_3 . The aqueous Na_2CO_3 solution was contacted with clean crushed reservoir core at a 5:1 liquid/solid ratio. Samples were agitated periodically during the 40-day time period. Because it is known that aqueous mixtures in contact with sandstone core material can acquire a small amount of alkalinity from the sandstone, equivalent samples containing only NaCl and crushed core were also monitored.

Over the time period, pH decreased by about 0.2 pH units. Total alkalinity of the samples actually increased. The increase in alkalinity was because of the effect of the sandstone described above, and corrected values are reflected in the curve in Figure 12 that is described as "total alkalinity less sand alkalinity." The actual loss of alkalinity because of reaction with sand over the 40-day interval was 0.003 meq/ml. The results indicate that in the reservoir there will be minimal loss of alkalinity because of reaction with reservoir rock. This result also indicates that deposition of mineral scale at production wells will not be a very severe problem during the field test.

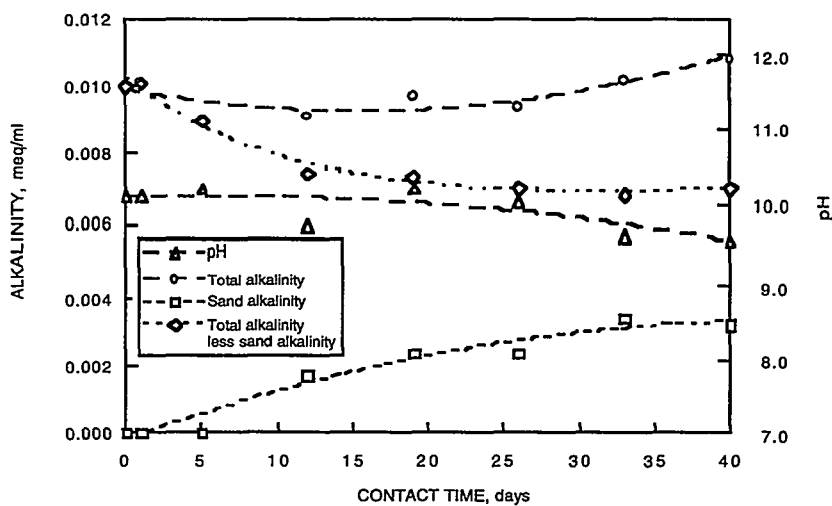


Figure 12 Consumption of Alkali by Crushed Warden Core

The field test will be probably be conducted with ASP and chase mixtures that contain 1,000 mg/l of Alcoflood polymer. Figure 13 shows the apparent viscosity of several concentrations of the polymer in Velma rural water. At typical reservoir shear rates of 3–6 sec^{-1} , the viscosity of 1,000 ppm polymer in Velma water is about 30 cp.

Figure 13 also shows the viscosity of various dilutions of the freshwater polymer mixture with reservoir brine. Notice that dilution of the freshwater polymer mixture 50:50 with reservoir brine results in a viscosity of about 8 cp. This illustrates the fact that a large volume of polymer should be injected behind the main ASP slug to maintain mobility control during the project. It is expected that injection of 0.25 PV ASP mixture will be followed with 0.50 PV of polymer. This should help to make sure that the oil bank is moved to production wells.

Very good results have been obtained when the polymer mixtures were injected through field cores. Figure 14 shows a typical injection pressure profile during injection of several pore volumes of polymer. There has not been any evidence of difficulty in injecting polymer through field cores. Even when several pore volumes were injected, injection pressure never continued to increase after equilibrium pressure was reached.

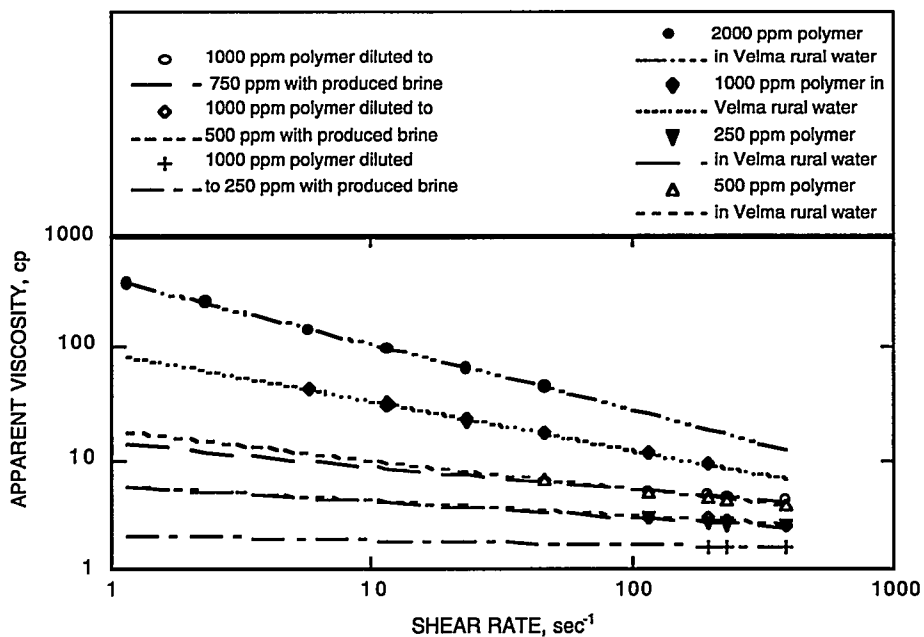


Figure 13 Apparent Viscosity of Allied Colloide 1275A Polymer

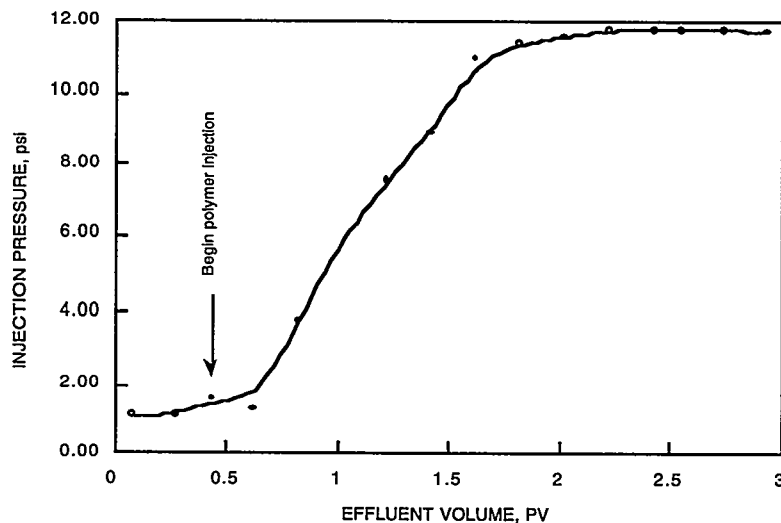


Figure 14 Injection of 1275A Polymer in Field Core

Interaction occurs when polymers and surfactants are mixed together. This interaction is usually detrimental to mixture stability. The interaction of polymer and surfactant are usually reflected by phase separation and rheological degradation. Often, viscosity will increase for a short period of time and then rapidly degrade as interaction continues. Polymer-surfactant interaction was shown, however, to be minimal for the surfactant/polymer mixtures that will be used in the field test. Figure 15 shows the viscosity of two surfactant polymer mixtures over a time period of 35 days. Initially, viscosity increased as expected. However, instead of then decreasing, the viscosities of the mixtures stabilized over the time period. These results indicate that rheological properties are likely to be maintained as the polymer and surfactant propagate beyond the wellbore and through the reservoir.

The results of representative corefloods conducted with Berea and field cores are shown in Figure 16. (Individual data points in the figure are labeled as Permian 5 sand (LNU), Permian 6 sand (LNL), or Berea (LNB). The results indicate that residual oil saturations near 12% PV are very possible for the field test if relatively large volumes of chemicals are injected. The corefloods shown in the figure were all performed with an ASP formulation that contained 0.50% Witco 2094 surfactant, 0.30% STPP, 2.25% Na_2CO_3 , and 1,000 ppm Alcoflood 1275A polymer mixed in injection (Velma rural) water. Exceptions are LNL-1, which was performed with 1.0% Witco 2094 surfactant and LNB-21 and 22, which used 0.50% of OCT ORS-62 surfactant in 1.70% Na_2CO_3 . In each flood, the ASP mixture was preceded by a small alkaline preflush and followed with 1,000-ppm chase polymer.

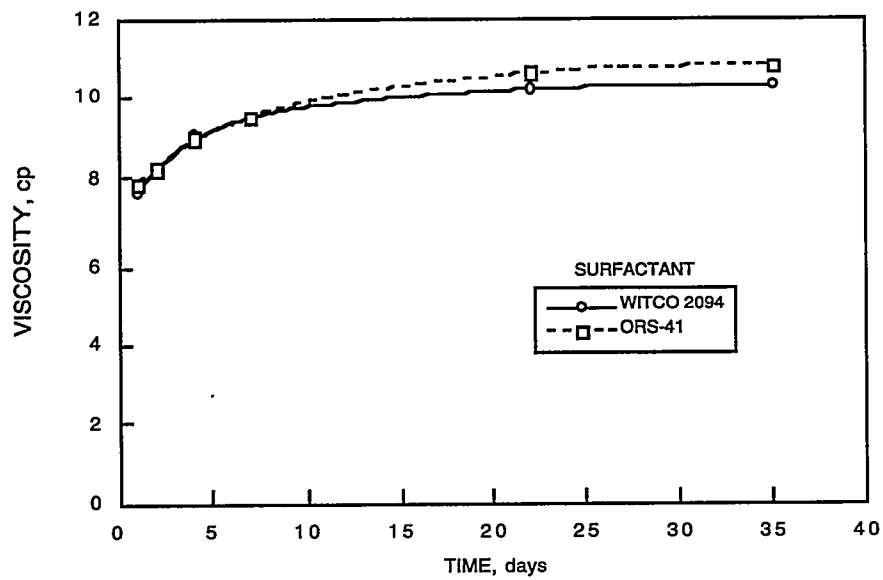


Figure 15 Viscosity of Surfactant-Polymer Mixtures

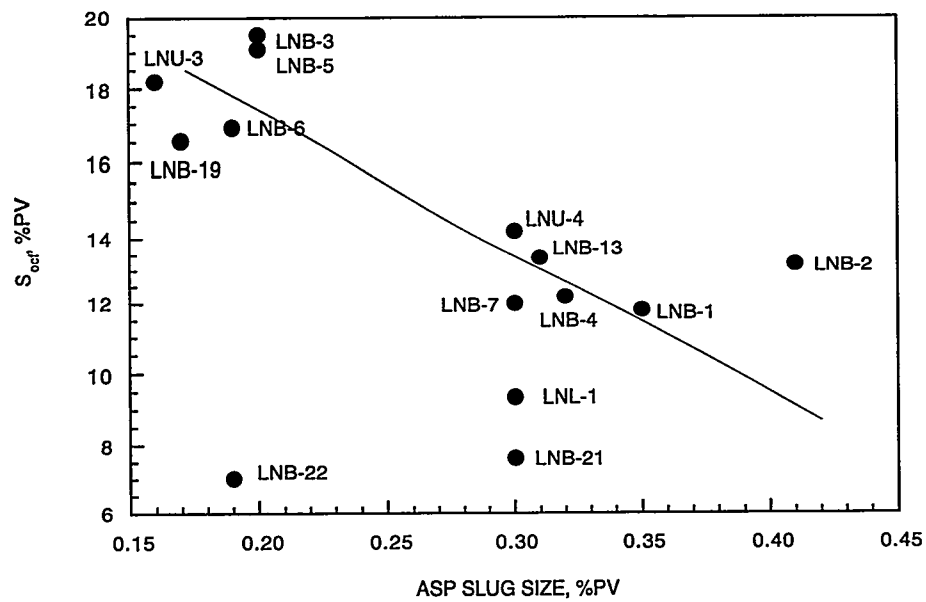


Figure 16 Core Oil Saturations (S_{oct}) after ASP Chemical Floods

The floods that recovered the most oil were LNB-21 and LNB-22. This series of floods with ORS-62 surfactant was the only series of floods which reduced residual oil saturation to less than 8%, and the flood conducted with 0.19 PV of ASP mixture (LNB-22) performed equally as well as injection of a larger ASP slug (LNB-21). Floods LNB-21 and 22 are compared in Figure 17. The rate of oil production was about the same for the two injection strategies.

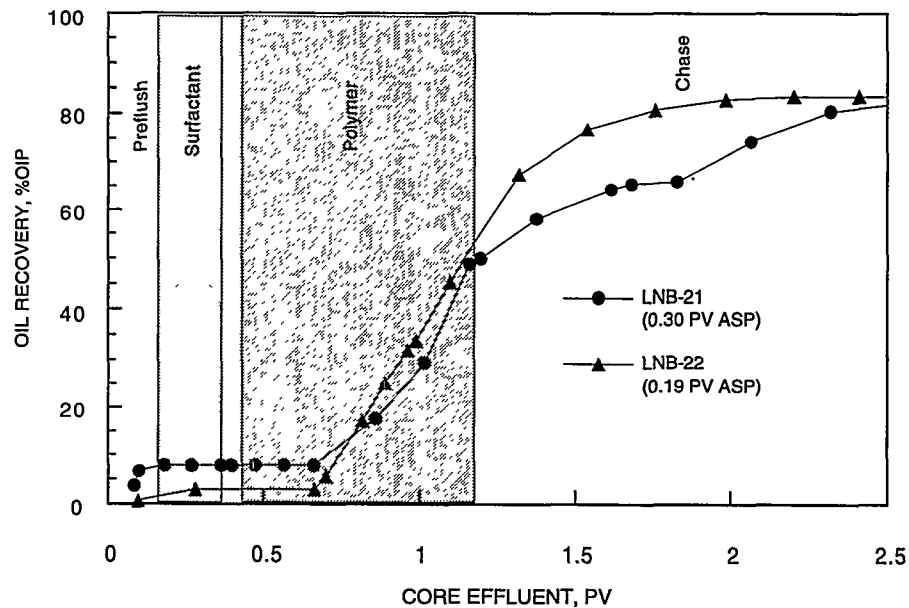


Figure 17 Oil Recovery with ASP Chemical Formulations That Contain 0.50% ORS-62 Surfactants, 0.30% STPP, and 1.7% Na_2CO_3 in Velma Rural Water

8.0 INJECTION PLANT

The injection facility has been designed and is being constructed. A floor plan is illustrated in Figure 18. There are several different designs that can be used for injection plants. Variations of the facility could, for instance, locate the surfactant tank completely outside the main building. This would be an advantage when the surfactant tank requires no heating (to reduce surfactant viscosity to allow pumping). Typically, many commercially available surfactants have high viscosity at ambient temperature, but some surfactants are available that have low viscosities at low temperatures. Another consideration in locating the surfactant tank is flammability. The surfactants that exhibit low viscosities tend to be flammable, in which case completely separating the surfactant storage area from the main building would have advantages.

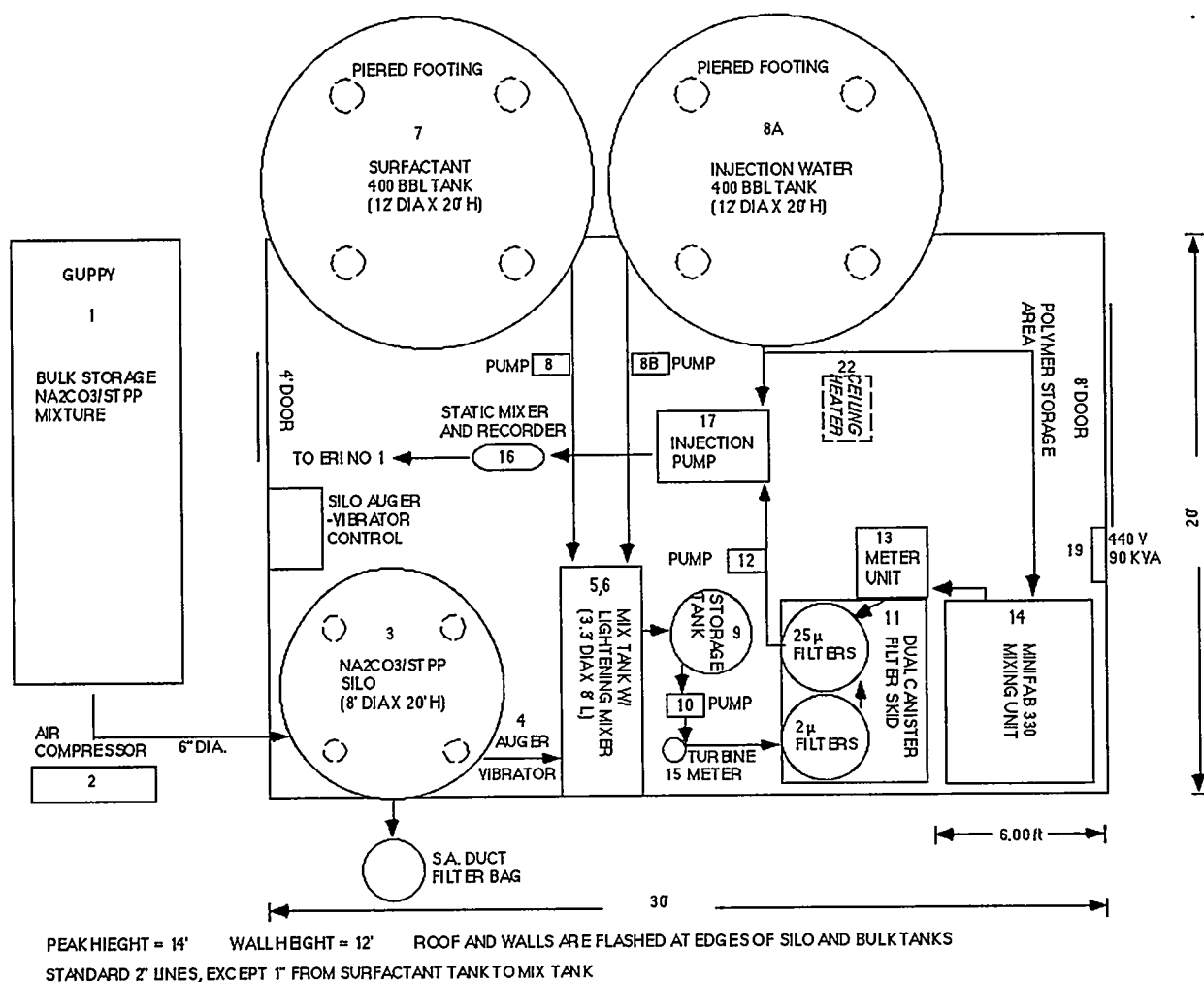


Figure 18 Warden ASP Injection Facility

Because freshwater can freeze, placing the water storage tank partly inside the building may be advantageous for heat transfer to the storage tank. However, for this project water will be used so rapidly that freezing will be a problem only if the plant shuts down for a long time. The water line between plant and tank should be heated during freezing weather. In this Warden project, the freshwater supply is very reliable, so storage of large amounts of water has not been deemed necessary.

Storage and use of the alkali can be a problem that is not easily solved, depending on the availability of used equipment and the project budget. Typically, about 2 to 4 weeks supply of alkali should always be on hand. This is somewhat dependent on the reliability of alkali delivery. Typically, truck loads of alkali will weigh about 22.5 tons and occupy about 1,100 ft³, depending on alkali density. Several grades of sodium carbonate are available. (The sodium carbonate for the Warden project will be preblended with a small amount of STPP.) Alkali

storage can be addressed in two ways. First of all, the bulk of the alkali can be stored in a *guppy* (an oil field term for a mobile storage unit, or truck trailer) as shown in Figure 18. However, the current procedure in some projects is to place all the alkali into large silos, thereby eliminating problems (caking) in transfer to silos and eliminating the need to rent a *guppy*. However, if used silos are unavailable, the cost of constructing a new silo is considerable, and the *guppy* option should be considered. At the Warden site, researchers are investigating the use of a fiberglass cone which will have multiple applications in the oil field even after the ASP project is complete. In any case, a screw-type feeder is needed between the alkali silo and the mix tank in the plant. Feeder control can be either manual or electronic.

The facility is designed to provide a continuous process stream that can be controlled with one part-time employee. Plant output will be 300 bbl/day to comply with the Oklahoma Corporation Commission injection well permit. Plant capacity is actually about 900 bbl/day, a value that could be increased by adding a second mix tank. This capacity will allow project expansion in the field, if pilot test results are favorable. Plant parameters can be adjusted over a wide range.

STPP is a sequestering agent that prevents precipitation of hardness ions from the injection water stream. Solid Na_2CO_3 and STPP will be preblended in the proper ratio before delivery to the plant. The polymer and polymer wetting equipment shown in Figure 18 will be purchased from Allied Colloids, a major supplier of polymeric materials used in oil fields. For injection of a chemical mixture that contains 1,000 ppm polymer, 1.60% Na_2CO_3 , 0.30% STPP, and 0.50% surfactant, the Minifab 330 output stream could be, for example, 67 bbl/day of 4,500 ppm polymer. The output stream from the mix tank would contain 0.64% surfactant, 2.06% Na_2CO_3 , and 0.38% STPP at an output rate of 233 bbl/day. This rate would allow for a residence time in the mix tank of 30 minutes, which is 5 times the required time for dissolution. From the mix tank, the surfactant/ Na_2CO_3 /STPP stream goes to the storage tank. While the storage tank empties, a fresh mixture is being prepared in the mix tank, thus permitting a continuous process. Blending the two chemical streams at the main injection pump would produce the desired concentrations at the total 300 bbl/day injection rate.

9.0 SUMMARY AND CONCLUSIONS

A reservoir was selected for an ASP field pilot test, and a working relationship with the field operator was established. Experiments conducted with cores and fluids from a reservoir in Sho-Vel-Tum field indicate that the Permian sand(s) is a good candidate for ASP flooding. An injection well was drilled and completed, and core from the well was analyzed and used to conduct oil recovery tests. After laboratory evaluations, an ASP chemical system for field use was designed.

Separate tankage for the pilot pattern area was installed, and a field tracer test is currently being evaluated. Tracer test results to date indicate that there is no major fracturing in the No. 5

sand. There is indication, however, of some channeling through the high permeability sand. The field injection plant was designed, and construction is in progress. Several variations of injection plant design have been evaluated. Some plant design details, such as alkali storage, were dependent on the availability of used equipment and project budget. The surfactant storage facility design is dependent on surfactant rheology. Chemical injection is scheduled for December 1997.

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